Appendix C

Comments on the *Draft Transmittal Report*

Appendix C: Comments on the *Draft Transmittal Report*

This appendix includes the comment letters received on the *Draft Transmittal Report*. Responses to these comments are included in Appendix D. The comments in each letter have been coded to allow the reader to trace the responses back to the comments themselves. This coding was done using the Adobe Acrobat markup tool; to print a copy with the coding intact requires selecting "Document and Markups" from the pull-down list under "Comments and Forms" in the Adobe Acrobat or Adobe Reader print screen.

Pacific Gas and Electric Company™

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November 8, 2005

ELECTRONIC DELIVERY

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1K
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments on the Committee Draft Transmittal of the 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission.

Thank you for considering our comments. Please feel free to call me at (415) 973-6463 if you have any questions about this matter.

Sincerely,

Les Guliasi

LGG

Enclosure

Pacific Gas and Electric Company Comments on
The California Energy Commission's
Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission
Draft Transmittal Report

Introduction

PG&E takes this opportunity to comment on the Committee Draft Transmittal of *2005 Energy Report* Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report (CEC-100-2005-008-CTD) ("Draft"). PG&E appreciates the hard work and extensive discussion among the Energy Report Committee, CEC staff, and stakeholders that has preceded this Draft. Unfortunately, the Draft includes recommendations on resource requirements and policies that are not factually supported in this proceeding. As discussed below, PG&E respectfully requests that the Draft's conclusions on resource be revised in order to ensure the resource requirements are consistent with the CEC's technical analysis and promote the development of necessary, cost-effective, and environmentally beneficial generation. Additionally, PG&E believes that many of the policy recommendations included in the Draft are more appropriately discussed in the CEC IEPR report. Finally, PG&E recommends the Draft be revised to provide a more detailed evaluation of the cost impacts of the included recommendations and the subsequent costs to consumers.

In addition to these comments on the Draft, PG&E provides additional comments to the proposed revised Tables included in Appendix B, provided by CEC staff on November 7, 2005. PG&E appreciates the opportunity afforded by the Committee, acting upon PG&E's recommendation at the November 4, 2005, Committee hearing, to enable the IOUs and interested parties to confer with CEC staff to clarify the information presented in the Tables accompanying the Draft Transmittal Report. This extra step in the process was necessary to ensure that the Draft is credible and useful for resource planning in the CPUC's 2006 Long Term Plan proceeding. Our comments to the revised table are included in Appendix A of this document.

General Comments

This genesis of this report was CPUC President Peevey's assigned commissioner's rulings (ACRs) of September 2004 and March 2005 that the CEC would determine the appropriate level and range of resource needs for the 2006 long-term plan (LTP) for each investor-owned utility (IOU) within the IEPR process. PG&E and many other parties expected this process to follow the successful but informal cooperation between the CPUC and the CEC in assessing each utility's 2004 LTP, which made good use of the CEC staff's extensive resource planning knowledge. In short, PG&E expected that the Draft would provide an update on the forecasts in each utility's approved 2004 LTP, based on known and foreseeable changes since 2004, which have been expected to be

PG&E-1

modest. Instead the Draft presents forecasts that sometime refer to physical capacity and at other times to contractual capacity; that contradict other CEC assessments of resource need, and that mix new public policy discussion with what was supposed to be an objective, quantitative-based exercise.

PG&E-2

PG&E commented recently on the new public policy positions reflected in the Draft, especially in the areas of Distributed Generation and Combined Heat and Power. (See PG&E's comments of October 14, 2005 on the Draft IEPR.) Many of these new public policy recommendations have been inserted into the Draft, and, thus, we reiterate these comments in brief here. We believe the public policy positions should be removed from the Draft as they are outside the scope of this part of the IEPR proceeding.

The Draft's recommendations for PG&E requirements contradict all other analyses of Northern California resource needs

PG&E-3

The Draft's determinations of resource need and requirements contradict all other analyses of Northern California requirements, including the CEC's own July, 2005 analysis in this proceeding (California and Western Electricity Supply Outlook, Staff Report[1]). In particular, Table B-5 of the Draft presents PG&E-area "Base Demand Case" capacity requirements for the period 2009-2016, including a need for over 4,000 MW of new resources in 2009, 7,300 in 2010 and increasing dramatically beyond this timeframe.

This assessment is significantly different from the CEC's July, 2005 analysis, which projects that Northern California is adequately resourced through 2010. Further, the July analysis comports with the CEC's adopted 2004 Update to the Energy Report of a year ago, which reported that the PG&E area would have well in excess of 15% planning reserves through 2008 (based on an expected case)[2]. Additionally, the July 2005 WECC Power Supply Assessment projects Northern California will have a reserve margin of over 17% through 2009.[3] PG&E notes that it provided the same information on load and resources that was used in all of the 2005 analyses.

Resource Accounting Tables present regional contractual resource requirements, not IOU physical requirements

PG&E-4

In order to ensure that the Draft is credible and useful for resource planning, PG&E recommends that it be edited to clarify that the resource need presented represents the ***contractual requirements for load serving entities*** (LSEs) in the IOU planning area and not the physical requirements for new generating capacity or the contractual requirements of individual IOUs. As discussed above, previous CEC and WECC analyses demonstrate that Northern California has sufficient physical resources to meet its total energy requirements for the next several years, and the need determinations provided in this

[1] California and Western Electricity Supply Outlook, Staff Report[1], CEC-700-2005-019, July, 2005
[2] Integrated Energy Policy Report 2004 Update, CEC-100-04-006CTF, October, 2004, Table A-3
[3] WECC 2005 Power Supply Assessment, presentation by Stan Holland, WECC, at July 26, 2005 CEC IEPR Hearing

Draft presenting a range of contractual resource requirements. This clarification was discussed in detail by the Energy Report Committee at the November 4, 2005 hearing on the Report.

The Report should also be revised to emphasize the need requirements are planning-area requirements, not individual IOU requirements. The annual Resource Accounting Tables included in Appendix B of the Draft present loads and resources owned and controlled by both utility and non-utility LSEs. According to PG&E's calculation the "Additional Non-Designated Need" presented on the tables reflect not only PG&E's resource position, but also the net requirements for all other LSEs in the PG&E-Planning Area. PG&E-4, cont.

The Draft overstates electric resource requirements

The Draft tables included in Appendix B presents "Additional Non-Designated Need" for the PG&E planning area that significantly overstates current electric resource requirements by ignoring planned resource additions. In 2005 PG&E applied to the CPUC to assume ownership and complete construction of the 530 MW Contra Costa 8 generating plant, and has executed several long-term contracts with renewable resources. Further, PG&E is currently in the process of evaluating bids to procure up to 2200 MW, as defined and approved in PG&E's last CPUC-approved long-term procurement plan. While this is briefly discussed in the Draft Report these resources are not represented on the tables, and procurement to the CEC recommended amounts would result in significant over-procurement. PG&E-5

The tables do not accurately represent regional supply and demand. The tables present total "Service Area Demand" for the IOU planning area, but for supply resources only includes the "claimed" capacity of generation rather than the total capacity available in the market. The table presents "existing capacities" for only those resources claimed by LSEs in their submitted supply forms, but many existing generation resources currently have no firm capacity sales contracts and, as such, this capacity would not have been claimed and is not included in this resource balance. The result is that requirements are overstated since available capacity not under contract, or new and un-contracted capacity that becomes available during the forecast period, is not considered to be regional resources. For example, PG&E's portfolio includes over 4000 MW of expiring DWR-contracted resources. It is highly unlikely that this generating capacity will disappear, and will be available for contract after the DWR contracts for this capacity expire. PG&E-6

Replacing aging power plants will neither meet customer requirements nor reduce costs

The Draft includes a policy recommendation that IOUs should replace capacity from what the CEC had deemed to be aging power plants. It assumes that these resources will be retired by 2012 and proposes that the investor owned utilities should replace this capacity, specifically proposing "To facilitate the retirement of these aging power plants, PG&E-7

the Energy Commission has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity….”(p.46) This apportionment of new capacity requirements without consideration of utility need or cost raises several troubling concerns.

The Draft has failed to provide any basis for the retirement assumption. Most of the proposed retiring resources located in Northern California are not utility owned, and PG&E is unaware of specific retirement plans for these resources. If utilities were to prospectively replace these resources and they are not retired, the resulting stranded costs would be substantial. PG&E notes that it is planning to retire the Hunters Point Generating Station in 2006 and the Humboldt Bay Generating Station prior to 2010.

PG&E-8

Further, requiring the utilities to replace this non-utility generation will result in subsidization of non-utility energy service providers and direct access customers by utility customers. The CEC reports that IOU loads represent approximately 60% of statewide electricity demand, yet expects them to replace all of the aging plant capacity, much of which is currently sold to non-utility LSEs. The likely result of this will be that utilities would incur the cost of replacing this generation, and the existing, less-expensive generation will be contracted by non-utility participants.

Load forecast will require updating for CPUC Long-Term Procurement Plan

The Draft recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC’s 2006 long-term procurement proceeding (LTPP). The Draft offers the following guidelines for when and how adjustments to the numbers would be appropriate.

> In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate….(page 55)

PG&E-9

PG&E disagrees with the above statement, and believes that adjustments are appropriate. The range of annual average growth rates for PG&E energy and peak demand over the period 2004-2006, as shown in Table 11, page 75, appear reasonable. However, as the long term planning process moves into the CPUC phase, these growth rates must be “calibrated” to recent levels of observed demand in order to produce more realistic estimates of MWh and MW demand during the forecast horizon. Staff’s revised projections, as shown in the Draft, are currently calibrated to 2004 observed demand.

Allowing for another update, which could still rely on the staff's solid growth rates, will avoid the very real possibility that staff's 2008-2016 projections in MWh or MW will be inconsistent with more recent observed data on energy use and peak demand that is not now available but may be available prior to the filing of the IOU's 2006 long-term procurement plans.

Energy Efficiency should be treated in a consistent fashion throughout the forecast horizon

The current analysis underlying the Integrated Energy Policy Report does not include PG&E's full forecast of energy efficiency savings in a manner consistent with the way PG&E treats this demand side resource. The Draft report treats forecasted energy efficiency savings beyond 2008 as a supply-side resource. There are two problems with such treatment: (a) it makes comparisons difficult; and (b) it incorrectly reduces the cost-effectiveness of future energy efficiency programs, since they no longer receive the credit they deserve for reducing the need for reserves. PG&E-10

The inconsistent treatment of targeted energy efficiency savings in the Draft creates confusion. For example, Table 6 suggests that the LSE's aggregate forecasts for the PG&E planning area are lower than the staff's projection. However, as PG&E pointed out in its June 30th workshop presentation, the forecasts are not comparable. If placed on a comparable basis, the aggregate LSE projections for PG&E's planning area are very likely to be above, not below, the levels projected by CEC Staff.

PG&E requests that the CEC avoid confusion by modeling energy efficiency savings as a reduction to projected demand throughout the forecast period.

The Draft must distinguish between customer-scale distributed generation (DG) and large combined heat and power (CHP) generating facilities

As PG&E has noted in comments on the Draft IEPR, the IEPR Committee has used the terms "Distributed Generation ("DG") and Combined Heat and Power ("CHP") interchangeably. The lack of clarity about when the CEC refers to DG and when the CEC refers to CHP is confusing and can even be misleading. PG&E-11

The terms "DG" and "CHP" encompass a very broad range of facilities with varying levels of efficiency, air emissions and other environmental impacts, and system impacts, from small residential photovoltaic systems to very large cogeneration plants. As such, policies should be developed with a careful consideration of the very different forms of DG and CHP.

PG&E recommends that the final Report include a clear definition of distributed generation, and continues to recommend the following:

> Distributed generation is electricity produced on a customer site from generators under 10 MW in size that are interconnected to the utility distribution system and

that are designed predominantly to serve load at the customer site or over the fence to one or two adjacent customers.

PG&E appreciates the CEC's effort to hold utilities revenue neutral through reinstitution of an Electricity Revenue Adjustment Mechanism. However, PG&E is disheartened by the implication that PG&E is somehow opposed to CHP and other DG because the policies proposed by the CEC run counter to PG&E's shareholder interests. This is not the case. As we explained to the CEC in a letter to Commissioner Pfannenstiel on September 8, 2005, PG&E's shareholders are indifferent to the amount of DG installed by our customers because various revenue adjustment mechanisms ensure that PG&E recovers any costs created by departing load..

PG&E supports DG as one of the choices our customers can make to meet their energy needs. Consistently throughout the IEPR process, PG&E has been supporting inclusion of cost benefit analysis in the decision making process. We have also consistently called for thoughtful policy decisions that are informed by cost benefit analysis rather than policy recommendations that support DG or CHP without including cost considerations. We do this because any uneconomic policy recommendations will have a negative impact on our customers (NOT our shareholders). If there is to be such an impact, it should be in carefully considered situations only, where the total resource costs justify it or where overwhelming policy considerations justify limited impacts on other customers. PG&E-12

Existing and new CHP are not necessarily fuel-efficient, cost-effective or environmentally superior to other thermal generation

The Draft makes several policy recommendations for CHP that are essentially the public policy advocacy positions of current cogeneration companies: that the IOUs should buy all electricity from CHP plants in their territories under standard offer contracts of at least ten years duration; that the CEC and CPUC should develop a yearly procurement target for CHP; and that the IOUs should be required to schedule CHP power at cost.

PG&E objects to the Draft adopting as recommended public policy these recommendations, without having considered the views of other stakeholders and interested parties. During the October 6, 2005, Committee hearing on the 2005 IEPR Committee Draft Report PG&E offered oral and subsequent written comments regarding its position on the benefits as well as the difficulties encountered with its cogeneration experience. None of PG&E's observations are reflected in the Draft. PG&E-13

The CPUC has jurisdiction under PURPA to establish wholesale rates for the purchase of power from qualifying facilities only. Not all CHP qualifies as QF power; thus the Draft's recommendation that the CPUC establish avoided cost rates and contract terms for the sale of all power from CHP may run afoul of federal law. For non-QFs selling to the utilities at wholesale, FERC has exclusive jurisdiction to set just and PG&E-14

reasonable rates. As we discuss below, FERC has jurisdiction to determine which cogenerators will be certified as QFs.

There are several good public policy reasons to reject or restrict the carte blanche long-term extension of existing QF cogeneration contracts and to oppose an open ended standard offer for new cogeneration facilities instead of market-based pricing and terms. PG&E has detailed its concerns in this area in our response to the Draft IEPR and extensively in our Avoided Cost testimony before the CPUC.[4] We reiterate these arguments briefly here. PG&E-15

First, a cost-effectiveness test (as the Draft IEPR concluded) is essential. Such a test would reveal that efficient cogeneration projects are in fact cost effective, can be and are economically competitive with other generation sources. Efficient cogeneration projects do not need the help of governmental programs and public subsidies. On the other hand, no public benefit is realized from economically propping up old, inefficient, cogeneration projects with outdated and inferior environmental controls, many of which are owned by large industrial and oil producing companies.

Second, the issue of expiring QF Power Purchase Agreements (PPAs) is presently being considered by the CPUC in its QF Avoided Cost Proceeding. PG&E submitted testimony in that proceeding, examining the validity of cogeneration industry claims regarding the benefits realized from cogenerated power in California. In its testimony PG&E rebuts these representations and shows that the most cost effective manner of providing for the state's future energy supply needs is not through the extension of the PPAs of old, inefficient cogeneration plants, but through the construction of state-of-the-art modern generation facilities.

Third, the capacity of older cogeneration units nearing the end of their contracts in PG&E's territory is not large. We think many of these plants may be able to continue generating electricity even if paid only market prices in the future, but even if we are wrong and the cogenerators fail to continue after their contracts expire, we would only be losing about 500 MW through the year 2010. This potential lost capacity is a small fraction of the capacity of new, already licensed but yet-to-be-constructed generation projects in PG&E's service area.

Fourth, the whole question of what types of CHP will be certified by FERC as qualifying facilities under PURPA is under review as part of FERC's implementation of the 2005 Energy Policy Act. The outcome of that review is uncertain, but will probably decrease the range of cogeneration facilities deemed to be QFs and eligible for avoided-cost pricing. The CEC and the CPUC should not act hastily to order the utilities to enter into contracts with facilities which may be determined to have too small a thermal load to be qualified as QFs.

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[4] See PG&E's prepared and rebuttal testimony in the CPUC's R. 04-04-003 and 04-04-025 of August 31, 2005 and October 28, 2005 regarding Qualifying Facilities Policy and Pricing Issues.

Finally, giving CHP a set aside while making renewables compete through RFOs would give CHP an advantage over renewables and would be inconsistent with the concept of renewables as the rebuttable presumption.

PG&E-16

Conclusion

PG&E believes that the Draft should be revised to present a range of utility contractual resource needs as envisioned by CPUC President Peevey's ACR. PG&E believes that such revisions must and should be included before the Draft is finalized and transmitted to the CPUC.

Appendix A

Pacific Gas and Electric Company
Comments on CEC IEPR
Proposed Revised Annual Aggregated Energy Resource Accounting Tables and Annual Aggregated Capacity Resource Accounting Tables

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the CEC Staff's proposed revised annual Aggregated Energy Resource Accounting Tables of November 7, 2005. These tables, included as Appendix B to the Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report, present the capacity and energy balances for the period 2009-2016 for the states load serving entities (LSEs). PG&E appreciates the effort that staff has expended developing these tables and understands the difficulty in presenting information is a comprehensive manner. PG&E provides the following recommendations for revising the tables in order to increase the clarity of the information so that it may be better understood by all reviewers and users.

First, PG&E recommends that the final Appendix B include a discussion of the methodology used in developing the tables. While discussion of the methodology is included in Chapter 5 of the Report, it would be very helpful to the reader of the tables to include the relevant methodology along side the tables. PG&E-17

Second, PG&E recommends re-arranging the tables in order to present the "Aging Plant Replacement" information at the bottom of the sheet and not on the table itself. PG&E appreciates that the Committee wants to present the capacity and energy from Aging Plant Replacement with the contractual resource need information, but the current table design is confusing. Aging Plant Replacement capacity and energy values are not used in any calculations on the table, and it is unclear why this information resides on the table. PG&E believes the CEC goal of presenting this information with the resource need information is achieved by simply including it beneath the table. PG&E-18

Finally, PG&E recommends the tables be renamed "(IOU***)-Planning Area*** (Scenario) Demand Case" rather than the current "(IOU) (Scenario) Demand Case" in order to reflect the nature of the information presented on the tables. The current table titles are something of a misnomer, as the tables include a composite of utility information and non-utility information. While PG&E cannot speak to the comprehensiveness of the non-IOU information, the tables do not present PG&E-specific demand case data. Changing the tables name would clarify for the reader that they are not examining utility–specific information. PG&E-19

SOUTHERN CALIFORNIA
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(U 338-E)

Southern California Edison Company's Comments On The Committee Draft Transmittal Of 2005 Integrated Energy Policy Report Range Of Need And Policy Recommendations To The California Public Utilities Commission

Before the
California Energy Commission

Rosemead, California
November 8, 2005

LAW#1257868

Southern California Edison Company's Comments On The Draft Transmittal

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I.

INTRODUCTION

Southern California Edison Company (SCE) submits the following comments on The Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission issued November 2005 (Draft Transmittal).

As the California Public Utilities Commission (CPUC) specifically asked the California Energy Commission (CEC) to use its Integrated Energy Policy Report (IEPR) process as "the appropriate venue for considering issues of load forecasting, resource assessment and scenario analysis, to determine the appropriate level and range of resource needs for load serving entities (LSEs) in California."[1] SCE initially comments on several areas where the Draft Transmittal has grossly misinterpreted the scope of the assessment the CPUC desired and made policy determinations which unfairly disadvantage investor-owned utilities (IOUs) and their bundled-service customers relative to all other participants in the market.

SCE-1

Among these issues are the Draft Transmittal's: a) recommendation that IOUs make commitments that are not required of any other LSEs; b) recommendation that the CPUC restrict renewable procurement through the requirement of standard contract terms; c) recommendation that the CPUC require IOUs to buy, through standard offer contracts all electricity from combined heat and power (CHP) plants in the IOUs' service territories at the IOUs' avoided costs; and d) publishing of residual net short estimates. As SCE has already addressed each of these issues in its October 14, 2005 Comments on the Draft 2005 Integrated Energy Policy Report it will not restate those concerns here, however, SCE

[1] *See* CPUC Assigned Commissioner's Ruling on Interaction Between the CPUC Long-Term Planning Process and the CEC IEPR Process, issued September 16, 2004, at 1.

incorporates those previous comments by reference. Accordingly, SCE limits its comments here to issues related to load forecasting (including mistakes and inconsistencies in the resource accounting tables) and renewable resources.

II.

COMMENTS ON LOAD FORECASTING ISSUES

SCE has a number of concerns related to the CEC's current load forecasting process. These issues have the potential to create serious problems between utility and CEC Staff forecasts in the future. SCE's other comments in this section apply directly to the Draft Transmittal.

A. Issues With The CEC's Forecasting Process and Models

As SCE has indicated throughout the IEPR process, the CEC Staff's underlying load forecasting process and models lead to serious and irreconcilable differences between utility load forecasts and CEC Staff load forecasts. These processes and models must be revised in order to provide the most accurate load forecast information.

Prior to deregulation, the CEC conducted bi-annual Common Forecast Methodology (CFM) workshops and hearings pursuant to regulations authorized by the Warren-Alquist Bill. At those hearings, which took place between the early 1980s and 1996, SCE forecasters developed opinions about the CEC's forecasting process. For example, SCE found that the CEC's methodology was not in the best interests of Californians or SCE's ratepayers because the CEC's in-house developed, end-use forecasting model was overly complex in construction and overly simplistic in results.[2]

SCE-2

[2] Such end-use models more accurately predict load for smaller customers than they do for larger customers.

SCE has been informed that the CEC Staff is, to a large extent, still using versions of the problematic models and processes to develop information for the Draft Transmittal. Thus, the Draft Transmittal contains many of the same shortcomings which pervaded the CEC load forecast determinations ten years ago. Some of the issues raised by the CEC's model are:

- What is the price elasticity in each of the residential, commercial, and industrial end-use models? If the price of electricity is raised by 10%, what is the first year, and continuing, impact on consumption and peak demand?
- What is the elasticity of the three models with respect to the primary economic driver—the income elasticity of the residential model, the employment or income elasticity of the commercial model, and the value added, or employment elasticity, of the industrial model? For a 10% change in the economic input, what is the first year, and the continuing, impact over the forecast period on consumption and peak demand?
- What is the "back-cast" accuracy of the models from 1985 through 2005? In prior CFM hearings, SCE frequently observed that when the model was run over a historical period, with recorded economic drivers, the trend predicting consumption was severely biased, as opposed to the results when a recorded consumption trend was utilized. In general, end-use models do not reflect growth rates of consumption that actually occur. Specifically, the CEC Staff model over-predicts the early part of the historical consumption period, and under-predicts the latter part of this period. This means that for the last year of recorded data, the model would predict significantly lower consumption than actually occurred. Extending a forecast from this point would

SCE-2, cont.

obviously lead to a low forecast. SCE has, for years, advised the CEC Staff of this problem with its model. The CEC's model is inherently flawed and should not be used as the basis for State forecasts. Despite SCE's warnings to the CEC Staff, this issue continues to be one leading to disagreements between utility forecasting staffs and the CEC's forecasting staff.

SCE-2, cont.

For all of the foregoing reasons, the model and processes used by the CEC Staff to develop the Draft Transmittal are fundamentally flawed and will continue to be so until the concerns raised by SCE here are addressed. SCE urges the CEC and the CPUC to promptly move to address these issues.

B. Specific Issues With Regard to the Draft Transmittal

1. The CEC's Draft Transmittal Should Include a Summary Table of Demand Forecasts, Which Accounts For Committed and Uncommitted Energy Efficiency and Demand-Side Management Programs

As a general concept, SCE believes that the CEC's reports should always publish one summary table reflecting the forecasts of demand that the CEC expects to show up at the meter. This means, that even if "uncommitted" energy efficiency (EE) and Demand Side Management (DSM) are handled as supply resources, and not deductions to the demand forecast (and if handled as a resource they should have a 15% reliability adder so they are equivalent to a reduction in demand, since that is how they will "show up" in the end), there should be tables wherein committed and uncommitted EE and DSM are both deducted from the demand forecast. Accordingly, when the Draft Transmittal details the level at which energy demand will grow over the next decade, that figure should have uncommitted EE and DSM deducted from the demand forecast. Uncommitted EE is still EE, it is not a generator, and, if funded, it will only have the effect of reducing demand. To

SCE-3

publish a demand forecast that only deducts committed EE and then provide a report that discusses California's needs, based on those demand results, exaggerates expected demand growth.

Uncommitted EE may not be funded, but it is still presumed "likely to occur," and should be deducted from the demand forecast in the CEC's summary table of the demand outlook for California. SCE has not identified such a summary table in this Draft Transmittal, and it should be added. If, however, the CEC Staff wants to compare "consumption forecast with just committed EE" against "consumption forecasts with committed and uncommitted EE deducted," it should at least emphasize that the ultimate intention is to forecast "demand" as what the meters will show, given the input assumptions, and not to leave a confusing trail of pieces of the demand forecast. SCE-3 (cont.)

2. <u>The Draft Transmittal Should Clarify That Labels of "Committed" and "Uncommitted" EE Programs Do Not Reflect SCE's Commitment to Such Programs</u>

SCE's internal forecasting methodology assumes that Public Goods Charge (PGC)-funded programs continue in the long-term. The methodology also looks to SCE's management for guidance as to the Company's commitment to future accelerated EE. Based on this direction, SCE includes estimates of EE for the 20 or 25 year forecast horizon. SCE does this so that its forecasts will show the impact on sales and demand of its policies with regard to EE. SCE-4

If the Draft Transmittal shows an early termination of PGC or advanced EE programs, this result is only because the CEC's instructions for filling out the IEPR forms specifically indicated that the normal assumptions SCE makes should be changed. For this reason, the labels of "committed " and "uncommitted" used in the Draft Transmittal should not be viewed as indicative of SCE's commitment to such programs, rather they are solely the product of the CEC's instructions for the IEPR process. As currently drafted, the Draft Transmittal does not make clear that the labels "committed" and "uncommitted" are not indicative of SCE's commitment to such EE programs. The Draft Transmittal should be revised to reflect this clarification. SCE-4, cont.

3. The Draft Transmittal's Resource Accounting Tables Should Include Uncommitted EE

The Draft Transmittal's reserve planning tables should include uncommitted EE with a 15% adder, such that uncommitted EE has the impact of reducing demand forecasts. Tables B7 through B12 in the Draft Transmittal do not appear to have done this. The failure to account for uncommitted EE has thus essentially overstated SCE future resource needs. SCE-5

4. The Draft Transmittal's Resource Accounting Tables Should Use Either Planning Area or Bundled Area, But Not Both In The Same Table

Tables B7 through B12 mix "planning area" and "bundled" load and supply data. It is also unclear which information in the tables is provided by the IOUs and which is the product of a CEC forecast. The CEC Staff should correct these errors and clarify the sources for their information. The CEC should also explicitly state its assumptions regarding the future of direct access and community choice aggregation. SCE-6

5. Treatment of Aging Power Plant Replacement In The Draft Transmittal's Resource Accounting Tables Is Confusing

Tables B7 through B12 confusingly address aging power plants. The CEC's intention with regard to these power plants should be clarified. SCE-7

III.

COMMENTS ON THE DRAFT TRANSMITTAL'S POLICY RECOMMENDATIONS

SCE is surprised that the vast majority of Draft Transmittal addresses policy issues. Instead of focusing on issues related to future procurement needs, the CEC uses the Draft Transmittal to promote its own policy positions. In this respect, the Draft Transmittal merely parrots many of the statements made in the Draft 2005 IEPR. For this reason, SCE incorporates fully by reference its written comments on the Draft 2005 IEPR. Additionally, SCE reemphasizes its position on the following issues in the Draft Transmittal.

A. The Draft Transmittal Contains Unsupported Recommendations Regarding the Need for Long-Term Renewables Contracts

Section 3.1.1 of the Draft Transmittal states, "[t]he lack of long-term contracts also hinders the development of renewable resources."[3] In, fact, SCE has recently executed long term contracts with eligible renewable resource project developers for up to1,350 MW of capacity. San Diego Gas & Electric and Pacific Gas and Electric Company have also executed long term contracts representing more than 1,100 MW and 225 MW respectively. All three IOUs have begun their 2005 solicitations, and SCE has received numerous bids. Thus, the CEC's assessment and recommendations on this issue are not supported by analysis and are contrary to fact.

SCE-8

Further, the CPUC has jurisdiction over the development of contract terms, approval of contracts, and monitoring and enforcement of progress towards renewable portfolio standard (RPS) goals. Accordingly, the Draft Transmittal's

[3] Draft Transmittal at 9.

inclusion of recommendations regarding this issue are unnecessary and should be deleted.

B. The Draft Transmittal's Recommendation's Regarding Standardized Contracts Should Be Deleted

In Section 3.1.2, the CEC states, "In addition to the previous discussion of long-term contracts, there was a significant volume of testimony in this proceeding regarding the need for standardized contracts."[4] This "testimony" consists of the unsworn comments of counsel and a limited number of Qualifying Facility representatives rehashing issues that have been fully resolved by the CPUC in D.04-06-014, which addressed and rejected arguments concerning the need for standardized contracts to implement the RPS legislation. Likewise, the issue of whether standardized contracts for cogeneration is an issue over which the CPUC has jurisdiction and which it is actively investigating in R.04-04-025. SCE-9

Because these issues are squarely, and solely, within the CPUC's jurisdiction, it is inappropriate for the CEC to use the Draft Transmittal to make policy recommendations to the CPUC. This is even more egregious since the CPUC has based its recommendation solely on the unsworn and unsubstantiated statements of clearly biased participants in an ongoing CPUC proceeding. For this reason, the Draft Transmittal's statements on this issue should be deleted.

C. The Draft Transmittal's Unsubstantiated Statements Concerning Cogeneration Should Be Deleted

In Section 3.1.2, the Draft Transmittal concludes its discussion of cogeneration with the following recommendations:

> ♦ By the end of 2006, the CPUC should require IOUs to buy, through standard offer contracts, all electricity from

[4] Draft Transmittal at 11.

> CHP plants in their service territories as delivered at the utility's avoided cost, as determined by the CPUC in R.04-04-025....
>
> ♦ Relative to system planning, the Assessment of California CHP Market and Policy Options for Increased Penetration determined a realistic goal of 5,400 MW of CHP by 2020, which is attainable if policies recommended here are implemented.

These policy recommendations prejudge the outcome of an ongoing CPUC proceeding in which the CEC is not a participant. Accordingly, this matter (sometimes described as a cogeneration portfolio standard) is the subject of hundreds of pages of sworn testimony recently submitted in R.04-04-025. Whether it is appropriate to adopt policies consistent with the CEC's recommendations is a matter squarely within the CPUC's jurisdiction pursuant to PURPA, and the CPUC has undertaken evidentiary hearings to consider the merits of this type of proposal. The notion of a mandatory set aside for cogeneration implicates a number of pricing, equity and environmental issues which are only scantly addressed in the Draft Transmittal or in the CEC's prior analysis of cogeneration, and by such omission, ignores the detrimental cost and environmental consequences of this policy on bundled-service customers. One has to reflect on the billions of dollars Californians have already paid to subsidize cogeneration under its previous must-take, standard contract model. For this reason, the CPUC should only adopt policies that are consistent with State and Federal law, which result in value for ratepayers and which guarantee the claimed benefits of cogeneration for the State of California, particularly with respect to claims of fuel efficiency and reduction of natural gas consumption.

SCE-9, cont.

Because the Draft Transmittal's recommendations on this matter are contrary to measured analysis, not based in fact, and appear to be premised on flawed assumptions, they should be deleted. SCE-9, cont.

D. The Draft Transmittal's Attack on the CPUC's Decision Approving the IOUs' Least-Cost/Best Fit Methodology Should Be Deleted

In Section 3.2 of the Draft Transmittal, the CEC states, "A recent review by the Energy Commission of evaluation criteria indicated significant shortcomings in the market value and portfolio fit criteria that are currently being used by utilities."[5] The RPS legislation, as implemented by the CPUC is sufficient to sort bids on the basis required by statute. For this reason, the Draft Transmittal should delete any reference to this issue.

E. Transmission Project Recommendations

SCE agrees with the Draft Transmittal's assessment of transmission in Section 9.3. It is imperative that the CPUC do whatever it can to move transmission projects forward. SCE-10

SCE notes, however, that the approval, construction and availability of transmission is integrally related to the resource potential for renewable development, and the Draft Transmittal fails to make recommendations that would even remotely support assertions concerning the State's ability to tap into the potential often claimed by the CEC.

For example, the CEC's Renewable Resources Development Report asserts, with little if any substantiation, that there is 63,000 MW of potential concentrating solar power available in Imperial, Kern, Los Angeles, Riverside and San Bernardino counties. Yet the Draft Transmittal does not discuss the facilities and facility SCE-10, cont.

[5] Draft Transmittal at 16.

upgrades that would be required to develop any of this potential. This disconnect between the CEC's recommendations on accelerated renewable development and the need and recommendations for transmission facilities to accomplish renewable penetration at levels greater than 20% is at best a troubling lapse, and certainly requires further consideration.

SDGE
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November 8, 2005

California Energy Commission
Dockets Office
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RE: Docket No. 04 IEP 1K – Sempra Energy Utilities Comments on the 2005 Committee Draft Transmittal Report

Dear Commissioners:

On behalf of the Sempra Energy Utilities, San Diego Gas and Electric and Southern California Gas Company, attached are comments in response to the 2005 Committee Draft Transmittal Report, Range of Need of Policy Recommendations to the CPUC. We appreciate the opportunity to provide comments and participate in this important process to ensure that California achieves its energy resource needs.

Sincerely,

Bernie Orozco

Sempra Energy Utilitites Comments on the
Committee Draft Transmittal Report, Docket No. 04 IEP 1K

During 2005, the California Energy Commission (CEC) has undertaken extensive proceedings to address a wide range of energy issues important to California as part of the CEC's Integrated Energy Policy Report (IEPR) proceeding. The CEC has prepared a Draft Report, released on October 25, 2005, that will be transmitted to the California Public Utilities Commission (CPUC) and used in the CPUC's 2006 resource planning process. The Draft Transmittal Report communicates to the CPUC the CEC's assessment of range of need and policy recommendations for this joint resource planning effort.

San Diego Gas & Electric Company (SDG&E) appreciates the hard work of the CEC throughout this undertaking, and particularly recognizes the dedication of the IEPR Committee and CEC staff in this process. SDG&E and SoCalGas, in addition to other utilities and stakeholders, contributed substantial analysis and data as part of this effort and have also participated in many of the IEPR hearings, including the one held on November 4, 2005 addressing the Draft Transmittal Report. SDG&E would also note that many of its comments offered regarding the Draft Committee Report,[1] dated September 2005, are equally applicable to this Draft Transmittal Report.

To summarize, SDG&E urges the CEC to recognize that a balanced approach to solving the state's most vexing and critical resource and transmission planning issues will be essential to achieving adequate, reliable, and affordable energy supplies for all Californians. Most would agree that today's pressing problems require additional supplies and the transmission needed to get those supplies to loads. Even in this simple statement is a requirement for balance and trade-offs, however. New generation, built far from load centers, will require new transmission. Existing supplies, denied access to market by transmission congestion, cannot address load needs. SDG&E is concerned that the current Draft CEC IEPR Reports have not sufficiently achieved this balance and send conflicting messages.

SDG&E also observes that at times the utilities receive more policy guidance and targets from regulators than can realistically be accommodated into their resource plans. Trying to simultaneously meet every goal, no matter how individually worthy, can result in greater than necessary resource additions at higher than necessary costs to consumers. Thus, policy guidance from this IEPR should come with the flexibility needed to allow those carrying out the policy to achieve the goals in a manner that balances meeting the goals with reasonable costs for consumers. In sum, achieving a goal one year later than planned at a lower long-term total cost to consumers should not be viewed as failure, but should be an acceptable plan.

Sempra-1

The Draft Transmittal Report reflects a lot of hard work by the CEC Staff, and many positive aspects of the Draft Report are not addressed here by SDG&E. Rather, we focus on several areas that SDG&E strongly urges the CEC to revise before adopting a final report for transmittal to the CPUC. If the CEC is unable to make the changes advocated here, SDG&E will continue to

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[1] See SDG&E Comments filed on October 14, 2005.

challenge these aspects of the CEC's analysis to the extent these issues are advanced in the CPUC's resource planning proceeding.

Load Forecast and Uncommitted Energy Efficiency

SDG&E has serious concerns regarding the combination of the load forecast and uncommitted energy efficiency (EE) amounts used in the report for years 2009 – 2016. SDG&E cannot support the report as currently drafted because subtracting future EE goals from Staff's load forecast results in a net need that substantially underestimates capacity and energy needs from 2009 through 2016. As Staff stated in the Transmittal Report, "Savings that SDG&E attributes to future DSM programs may to some extent be already accounted for in the Energy Commission's model as part of the effects of building decay, equipment replacement, price effects, and building and appliance standards" (Draft Report, p. 80). SDG&E agrees with this statement and believes future EE efforts are already embedded in the Staff load forecast. However, the report also shows the full amount of future EE goals as a resource. Subtracting the full amount of uncommitted EE double counts the impact of future EE resulting in an incorrect assessment of future resource needs. Sempra-2

If the load forecast and uncommitted EE are adopted as presented in Staff's resource plan, the resulting capacity need for SDG&E's service area would only increase by a total of 75 MW from 2009 to 2016, or roughly 10 MW per year. To put this in perspective, Staff's load forecast including all energy efficiency savings for the years 2005-2008 projects an average load growth of 82 MW per year. In recent history, SDG&E has experienced peak load growth in excess of 100 MW per year. Thus, the use of Staff's load forecast combined with the total amount of uncommitted EE produces an unrealistic resource plan that will underestimate future resource needs by about 500 MW.

This problem of double-counting future EE savings does not apply only to SDG&E. Using the area peak demand forecasts and the uncommitted EE savings for all three of the IOUs as presented in Tables B-5, B-11, and B-17, one can calculate that the combined capacity need of all three IOUs totals 405 MW for the 2009-2016 period. Therefore, adoption of this resource plan will seriously underestimate the statewide need for resources.

Lastly, SDG&E notes that although the Transmittal Report claims to provide a range of need, the range is so narrow that for all practical purposes there is no range. Staff's low scenario is only 37 MW below the base case in 2016 and their high scenario is 118 MW above the base case in 2016. A range of only 3% over twelve years into the future is much too narrow. Sempra-3

Resource Accounting

In reviewing the tables for SDG&E (B13-B18), a number of changes need to be made to properly account for the total resource need and how reserves are calculated. These changes are needed because the current tables would result in SDG&E acquiring substantially more resources than are needed and result in a 40-60% reserve margin depending on the year. This excess reserve is the result of three major items that all need to be corrected before the final tables are submitted.

First, adding procurement to account for the potential replacement of aging power plants is unnecessary. SDG&E's submitted resource plans meet the forecasted loads and the required reserves for SDG&E's bundled load. Thus, SDG&E has already addressed this issue. SDG&E's plan added resources that replace the aging plants (or contracted with them) as a supply source. As such, there is no need to add an increment of procurement in either the energy or capacity table.

Sempra-4

It should also be noted that the possible impact of retiring plants will impact supplies available to all customers, not just bundled customers of the IOUs. SDG&E is already undertaking long-term planning and an orderly procurement process to deal with these older units. SDG&E is adding over 1,100 MW of new plants to its service area and is currently studying the addition of a major new transmission line, both of which will allow for the retirement of some of the existing aging plants. SDG&E also plans to undertake its future procurement well in advance of its needs to allow new plants to compete with the older plants.

Sempra-5

Second, the tables calculate an amount of capacity needed to meet a 15% reserve margin based on total system load, not the IOUs' bundled load shown in the table. This would in essence be requiring the IOUs to procure reserves for all load serving entities (LSEs). The CPUC has adopted a resource adequacy program that requires each LSE to procure its own reserves. The IOUs are not responsible for procuring reserves for the total load in the service area. Thus, any reserve requirement in the table should be reserves for the IOUs' bundled load only.

Sempra-6

Third, the table as presented would result in SDG&E having to procure reserves for uncommitted energy efficiency and uncommitted demand response programs. This is contrary to the cost benefit analysis of these programs which assumes that these programs eliminate the need for reserves. These uncommitted resources will reduce the load in the future and thus reduce the need for reserves. The tables should either move these resource options up in the table and subtract them from load prior to calculating reserves, or "gross up" the amount of capacity available from these resources by 15%.

Sempra-7

Committed Interruptible and Dispatchable Demand Response

The line for Existing Interruptible/Emergency Programs for SDG&E is currently not correct. At the time the original forms were submitted to the CEC, SDG&E had 6 MW of committed interruptible programs and 30 MW of committed dispatchable demand response programs. At a very minimum, this total should be shown on this line and the line relabeled to state that it includes dispatchable demand programs as well as interruptible programs. However, it should be noted that since the forms were submitted, the CPUC has approved additional programs and SDG&E currently has programs that total 86 MW of committed interruptible and dispatchable demand response programs.

Sempra-8

Need to Update All Data Items

The report states that a number of line items in the tables will need to be updated and a number of them will not need to be updated as part of the CPUC's long-term procurement planning process. The reality is that all items should be updated. The data used by the CEC in these tables represent data provided to the CEC on March 1 and April 1, 2005. To meet these deadlines, the data had to be gathered months in advance. The CPUC's long-term procurement

Sempra-9

planning process should use the best data available at that time, and not data that in many cases will be over a year old. Because the IOUs will make financial commitments on behalf of their customers based on the outcome of the CPUC process, the CPUC decision should rely on the best available data. The IOUs will need to be able to update all line items. These will include but not be limited to updates to the load forecast to reflect 2005 actual, new commitments, changes in capacity ratings of units, changes necessary to comply with the CPUC's resource adequacy proceeding decision, and changes in resources that have been approved by the CPUC since the CEC data was submitted. Staying with year old data will not serve the interests of ratepayers.

Sempra-9, cont.

Other Items

In Section 7.3.1.4, the report implies that all Combined Heat and Power (CHP) is distributed generation, which is incorrect. In fact, the majority of the CHP that sells back to the IOUs are large generation stations that do not fit the definition of distributed generation. The report should treat DG and CHP as two different and distinct items.

Sempra-10

SDG&E also objects to the report's reference to a claim that the lack of long-term contracts hinders the development of renewables (Section 3.1.1, page 10). All of the contracts SDG&E has executed with renewables have been long-term contracts to enhance the development of new renewable sources.

Sempra-11

Conclusion

SDG&E appreciates the extensive efforts that the CEC has invested in this IEPR process. To ensure that the process moves ahead with the best interests of ratepayers represented, SDG&E strongly urges that the changes advocated here should be adopted by the CEC in its final Transmittal Report to the CPUC.

05.11.08

Comments of the Natural Resources Defense Council (NRDC) on the *Committee Draft Transmittal of* 2005 Energy Report *Range of Need and Policy Recommendations to the California Public Utilities Commission*

Docket Number 04-IEP-1K
November 8, 2005

Submitted by:
Audrey Chang, NRDC

The Natural Resources Defense Council (NRDC) appreciates the opportunity to offer these comments on the California Energy Commission's (CEC) *Committee Draft Transmittal of* 2005 Energy Report *Range of Need and Policy Recommendations to the California Public Utilities Commission* (Draft Transmittal Report). NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable energy services that Californians demand. We focus on representing our more than 130,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's electricity consumption.

We commend the CEC staff for distilling the *2005 Integrated Energy Policy Report* (IEPR) into a Transmittal Report to inform the California Public Utilities Commission (CPUC) 2006 procurement proceeding. Many of our comments presented here reflect those that we have presented regarding the IEPR as a whole, but some are specific to the Transmittal Report.

The Transmittal Report should include policy recommendations to the CPUC.

Some parties expressed surprise at the November 4, 2005 hearing that policy recommendations were included in the Transmittal Report. It is appropriate for the CEC to use this document to convey to the CPUC its recommendations that are relevant to and that will improve the CPUC's 2006 procurement proceeding process. NRDC supports the inclusion of these policy recommendations in the Transmittal Report.

NRDC supports the CEC and CPUC working together to adopt the greenhouse gas performance standard, without the use of offsets.

NRDC strongly supports the Greenhouse Gas Performance Standard proposed in the draft IEPR and further described in Chairman Desmond's memorandum dated September 22, 2005. This policy is needed both to achieve the Governor's GHG reduction targets and to protect Californians from the significant financial risks associated with additional investments in highly carbon-intensive generating technologies. We oppose the use of offsets to meet the standard because allowing for offsets would greatly diminish the risk mitigation benefits of the policy and discourage the investments in advanced technologies that are needed to achieve the Governor's long-term reduction targets. We support the CEC and CPUC working together to ensure that all of California will be protected from the financial risks of global warming pollution. NRDC-1

NRDC recommends that the Transmittal Report encourage the CPUC to direct the IOUs to perform portfolio analyses examining future resource fuel types.

The draft Transmittal Report correctly notes that the use of portfolio fit criteria has "value when looking at a single asset, [but] are less valid when examining a larger portfolio" (page 16). This points to an aspect of analysis that is currently missing from the IOUs' procurement process: true *portfolio* resource planning through examination of future resource fuel types.

Although an analysis of the future resource fuel types that the load-serving entities could expect to be part of their portfolios was not conducted for this 2005 IEPR, we strongly recommend that the CEC encourage the CPUC to require the IOUs to perform this sort of *portfolio* resource analysis as a part of their resource planning. To better inform California's energy policy, the IOUs should examine the likely future composition of their electricity mix, and the associated costs, risks and environmental impacts that customers can expect. We outline the need for this sort of true resource planning on pages 12-13 of our October 14, 2005 comments on the draft IEPR. NRDC-2

In addition, pages 44 and 47 of the draft Transmittal Report note that the CEC and CPUC share a commitment to implementing the loading order and thus preferred resources (energy efficiency, renewables, and distributed generation) are identified. However, there is currently no way to ensure that the last component of the loading order, clean fossil generation, is followed. Resource fuel type analysis by the IOUs using the "greenhouse gas adder" will help close this gap.

The CEC should recommend that the PUC's long-term planning process include a comprehensive risk analysis.

Assessing, managing, and mitigating risks is one of the utilities' most important and most challenging responsibilities in creating comprehensive and integrated resource plans. Similarly, overseeing the utilities' management and mitigation of risks is one of the CPUC's most important responsibilities in ensuring that customers receive reliable, affordable, and environmentally sensitive energy services. If ever a reminder was needed of this fact, the crisis of 2000 and 2001 showed forcefully that careful management of both financial and reliability risks is absolutely essential to the state's wellbeing.

While the CPUC has implemented a process for managing short-term price risks through the use of a Customer Risk Tolerance, it is the long-term planning process that enables the IOUs and the CPUC to compare resource alternatives in a manner that captures interactive *portfolio* effects. Without long-term integrated planning, a utility that analyzes procurement options one by one is likely to "miss the forest for the trees." Each individual investment decision may seem like the best decision, but the *additive* effect of the decisions and the impact on the overall portfolio would not be considered without true long-term plans.

This process should include testing a number of potential resource portfolios to determine their total long-term costs, to conduct a risk analysis of those portfolios under various scenarios, and to select an optimal portfolio that best meets the portfolio manager's objectives. Given the numerous risks in the electric industry, it is essential to conduct a risk analysis to test how robust each portfolio is in the face of various uncertainties. There are generally at least three different types of risks: (i) risks that can be quantified and for which historical experience can inform assessments of the future risk (e.g., load forecasts, natural gas price risk);[1] (ii) risks that can be quantified but for which no historical experience can inform the assessment (e.g., future regulation of carbon dioxide emissions); and (iii) risks that cannot be easily quantified, but can be qualitatively assessed (e.g., a change in FERC's market design, public acceptance of new resource siting, etc.). The preferred resource plan is generally the portfolio that has the lowest lifecycle cost (i.e., lowest anticipated long-term revenue requirement) and is most robust in the face of various risks, among other factors. The Commission can look to other utilities' risk analyses, including PacifiCorp, Idaho Power, Puget Sound Energy, for examples of what a portfolio-level risk assessment should include. Of course, a risk analysis will only be meaningful if the resource fuel types are identified and analyzed, as we discussed above.

The "range of need" should explicitly state what portion consists of contractual vs. physical needs.

The graphs showing the annual energy and capacity ranges of need that were presented by Staff at the November 4, 2005 hearing were extremely helpful in helping the reader visualize how the range of need was constructed. We recommend that these graphs be included in the final Transmittal Report. NRDC-3

The "range of need" currently encompasses both contractual and physical needs, but the distinction between the two is not always clear in the tables and graphs in the draft Transmittal Report. The CEC should avoid sending the unintentional signal that the entire amount of need is for new physical capacity that needs to be built, when some of this need can be fulfilled through contracts for existing physical resources. In addition, the additional need from retiring power plants should be separately identified.

The description of the CEC's demand forecast should be explicit about the treatment of energy efficiency and should include at minimum the energy efficiency that will be funded by the public goods charge (PGC).

As in the draft IEPR, it is unclear from the draft Transmittal Report text (section 5.1 and 5.3) whether no efficiency savings at all are included past 2008, or whether only PGC-funded savings are included similar to the 2003 IEPR. Since the PGC is legislatively mandated through 2011 and will not change during this time, it effectively serves as a minimum floor for efficiency investments during this timeframe and should be included in the "committed" energy efficiency in the demand forecast. Savings from PGC-funded energy efficiency programs can be estimated based on historical performance of energy efficiency programs. Further comments regarding the treatment of energy efficiency in the CEC demand forecast can be found on page 14 of NRDC's October 14, 2005 comments on the draft IEPR. NRDC-4

[1] Of course, while historical experience is extremely useful in assessing risks, this information must always be combined with informed judgment about the future.

In addition, it should be clarified whether the energy efficiency numbers apply to the IOU bundled load or entire service territory. It seems that the "uncommitted energy efficiency" shown in the Appendix B tables for each IOU does not match the energy savings goals set by the CPUC for the IOUs. Although these goals may be modified in future years, their current levels reflect the existing policy set for the IOUs, and the IOUs' plans should reflect this. NRDC-5

The utilities' decoupling mechanisms are effective in removing financial disincentives for any demand-side reductions, not just energy efficiency.

Page 14 includes the recommendation that "[a]pproaches such as the Earned Rate Adjustment Mechanism [ERAM], which were successful in keeping IOUs revenue-neutral for energy efficiency programs, could be implemented for CHP and DG." Indeed, ERAM, the *Electric* Rate Adjustment Mechanism was successful, and a new generation of decoupling mechanisms adopted by the CPUC for all the major IOUs has been key to California's successes in energy efficiency.[2] These decoupling mechanisms are strategy-neutral and will also help eliminate financial disincentives for any activities that would otherwise impact the IOUs' revenues by reducing their sales volume. NRDC-6

[2] For a discussion of the new generation of decoupling mechanisms, see Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal*, Volume 17, Issue 8, October 2004, pp. 52-62.

BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF DUKE ENERGY NORTH AMERICA ON THE 2005 COMMITTEE DRAFT TRANSMITTAL OF 2005 ENERGY REPORT RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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November 8, 2005

BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF DUKE ENERGY NORTH AMERICA ON THE 2005 COMMITTEE DRAFT TRANSMITTAL OF 2005 ENERGY REPORT RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Pursuant to the Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report, Duke Energy North America ("DENA") provides these comments for the Committee's consideration. For the reasons explained below, DENA urges the CEC to recommend to the California Public Utilities Commission ("CPUC") that 3-5 year "interim contracts" be pursued to shore up the availability of existing resources while additional work is completed with respect to development of full resource adequacy implementation and a formalized capacity market.

The Transmittal Report includes policy recommendations that are aimed at phasing out older power plants. The Transmittal identifies approximately 50 power plants throughout the state that have been relied on in recent years to meet peak demand.[1] The CEC advocates the replacement of these plants on a pre-ordained basis, presumably via long-term contracts with the utilities. To forward this policy recommendation, the CEC advocates imputing an additional capacity requirement to the IOUs, irrespective of whether those assets are in fact included in the utility's portfolio developed to meet customer needs and satisfy regulatory requirements such as

[1] This number excludes publicly owned utility generation assets that are similarly situated in terms of vintage to investor owned utility generation assets.

the Resource Adequacy Requirement ("RAR").[2] The rate of capacity phase-out is 25% of the utility's aged unit capacity per year beginning in 2009 such that the all the identified resources are retired by 2012.

DENA believes that the CEC's ultimate goals are laudable (namely more efficient and environmentally acceptable resources), but that the means of pursuing the goals through a strict phase-out approach may not be necessary as improved market structures are anticipated to be operating in that timeframe. However, as DENA has stressed for some time, a 3-5 year interim contracting approach for existing resources should be undertaken to maintain the availability of existing resources for reliability purposes pending full implementation of RAR and a formal capacity market.[3]

Duke-1

[2] See Transmittal Report, page 46:

> To facilitate the retirement of these aging power plants, the Energy Commission ***has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity and the average energy produced in 2002 through 2004***. In order to ensure that sufficient investment takes place in the next round of procurement to provide for the orderly replacement of the retiring plants with new resources, ***the Energy Commission is including the full amount of the existing capacity and average energy generation of these plants for 2002 through 2004 in the identified need for each of the IOUs for 2012 and beyond***.

[3] See, e.g., DENA's involvement before the CPUC in its *Comments of Duke Energy North America on the Proposed Decision of ALJ Wetzell Regarding Resource Adequacy Issues*, September 20, 2004 in R.04-04-003 arguing that the utilities should be given interim or transitional procurement authority to secure capacity in anticipation of RAR; *Opening Brief of Duke Energy North America on Electric Utility Resource Planning*, October 18, 2004 in R.04-04-003 arguing in favor of a interim contracting arrangement as described in testimony presented in that case; *Reply Brief of Duke Energy North America on Electric Utility Resource Planning*, November 1, 2004 in R.04-04-003, arguing for interim steps to maintain availability of existing capacity while focusing on the eventual development of a formal capacity market structure; *Comments of Duke Energy North America on the Proposed Decision of ALJ Brown Regarding Electric Utility Long Term Resource Plans*, December 6, 2004 in R.04-04-003 arguing for including authority for interim procurement contracts with existing capacity; C*omments of Duke Energy North America In Response to Commissioner's Ruling Regarding Interim Resource Adequacy Obligation*, February 18, 2005 in R.04-04-003; *Supplemental Comments of Duke Energy North America Concerning Latest Round of Workshops on Resource Adequacy Issues*, May 10, 2005 in R.04-04-003; *Comments of Duke Energy North America Regarding Draft Energy Action Plan II*, July 1, 2005 letter to CEC President Peevey and CEC Chairman Desmond; *Reply Comments of Duke Energy North America in CEC Docket 04-IEP-1D, California and Western Electricity Supply Outlook Report*, August 5, 2005.

With the institution of the RAR at the CPUC, older existing resources will retain value for reserves purposes. Stated differently, existing resources that may not have particularly advantageous heat rates retain important market value in terms of satisfying RAR and providing capacity required during peak periods. Whether or not the units are ultimately dispatched would be an issue that reflects either the contracting LSEs' portfolio or the system needs as determined by CAISO. Duke-2

The ability of these facilities to secure economic support over the longer-run will determine their retirement date. If, for example, a formalized capacity market is developed and the capacity from these resources is not supported in that market, it is reasonable to assume that an asset owner will decide from that market's price signals whether to retire or mothball an asset. Moreover, given the utilities' various competitive solicitations that should be expected during this time period, as long as existing resources (including those already under contract) can bid to provide longer-term resource commitments, then the market mechanism will replace these assets.

DENA believes that the "interim contracting" approach it has advocated for some time will help avoid potential capacity shortages between now and the first expected wave of new infrastructure around 2009. DENA's concern, and its proposed "interim contracting" solution, centers upon the failure of today's wholesale market structure to support existing capacity that does not have a bilateral contract with a load serving entity, and the potential risk to system reliability that could arise should these facilities retire before replacement resources are online. If, as is expected, the CPUC's RAR policy includes the local reliability area capacity requirement by 2007 *and* a formalized capacity market is developed quickly, owners of existing older generation will have market opportunities to invest in newer infrastructure that will provide better fuel efficiency and environmental benefits. Duke-3

The CEC shares DENA's concern about a potential capacity gap, and believes that the RAR policies and a formalized capacity market, when fully implemented, will provide a strong market-based mechanism to provide new capacity when and where needed. In the meantime, existing capacity should remain available through 3-5 year "interim" contracts to provide time for the implementation of those market mechanisms.

Duke-4

Accordingly, DENA requests that the CEC revise its recommendation to the CPUC and focus on the completion of RAR and implementation of a formalized capacity market, rather than simply long-term contracting by the utilities, but that "interim" contracting of 3-5 years should be taken as a "bridge" to maintain existing capacity during the full implementation of RAR. This suggested revision to the Transmittal Report will better reflect the efforts already underway at the CPUC and elsewhere, and will acknowledge that there are other market-based means of encouraging infrastructure improvement.

Duke-5

Respectfully submitted,

Melanie Gillette

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November 8, 2005

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BEFORE THE CALIFORNIA ENERGY COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of: Preparation of the 2005 Integrated Energy Policy Report	Docket No. 04-IEP-1K

COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE 2005 COMMITTEE DRAFT TRANSMITTAL REPORT

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BEFORE THE CALIFORNIA ENERGY COMMISSION
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COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE 2005 COMMITTEE DRAFT TRANSMITTAL REPORT

The Cogeneration Association of California[1] (CAC) and the Energy Producers and Users Coalition[2] (EPUC) submit the following comments to the California Energy Commission (Energy Commission) on the 2005 Draft Transmittal Report (Report). The comments are submitted pursuant to the Energy Commission's October 25, 2005 Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report.

CAC/EPUC supports the policy recommendations for CHP resources contained in the Report at pages 14-15. As stated in CAC/EPUC's October 14, 2005 comments on the draft IEPR, the recommendations address real obstacles

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[1] CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

[2] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California.

to CHP preservation and development and will facilitate retention of the many benefits which these resources provide to the State. The Report's recommendations are appropriately based upon a comprehensive review of the issues through staff and consultant reports, the receipt of both oral and written comments from all interested parties, and full day workshops on the issues.[3]

The Report's recommendations are also consistent with the energy agencies' efforts to coordinate the IEPR and procurement proceedings. The March 14, 2005 Assigned Commissioner's Ruling (ACR) addressed how the 2005 IEPR and 2006 CPUC procurement proceedings would be coordinated.[4] Specifically, the ACR sets forth what should be included in the Energy Commission's Transmittal Report as follows:

> *As part of the 2005 IEPR process, the CEC will also prepare a "Transmittal Report" for use by the CPUC in the 2006 procurement proceeding; that document will contain the specific information identified in Commissioner Peevey's ACR issued September 16, 2004, in R.04-04-003, and in D.04-12-048.* (ACR at 6)

Attachment A to the September 16, 2004 ACR sets forth the specific information required. Attachment A notes in pertinent part that the "*CEC's 2005 Integrated Energy Policy Report ("IEPR") process will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial cycle*." This process includes but is not limited to recommending "*broad, statewide resource preference policies.*"

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3 The Assessment of California CHP Market and Policy Options for Increased Penetration, April, 2005, alone is 185 pages long.

4 Assigned Commissioner's Ruling Detailing How The California Energy Commission 2005 Integrated Energy Policy Report Process Will Be Used In The California Public Utilities Commission's 2006 Procurement Proceedings And Addressing Related Procedural Details, R.04-04-003, March 14, 2005

Attachment A goes on to note that the "*CPUC's procurement process will produce IOU-specific procurement plans, require competitive generation solicitations, incorporate needed transmission upgrades and guide preferred resource acquisition to ensure resource adequacy on a biennial cycle beginning in 2006*." As part of this process the "*CEC provides ranges of likely need and resource assessment for individual IOUs* *__and statewide policy preferences from IEPR__.*" (emphasis added) Accordingly, the Report's recommendations for CHP are completely consistent with Commissioner Peevey's ACR.

The recommendations contained in the Report are also consistent with Governor Schwarzenegger's review of the Energy Commission's 2004 IEPR Update. In response to the recommendation in the IEPR that the forecasts, resource assessments, and policy preferences of the Energy Report would be incorporated into an explicit resource adequacy requirement for all retail electricity suppliers to guide resource procurement, the Governor replied:

> *The California Public Utilities Commission (CPUC) has already indicated in its recent rulings and decisions that the products of the Energy Commission's Energy Report will be used to guide long-term resource procurement in CPUC proceedings. Both agencies are to be commended for this effort.*[5]

More specifically, in response to the recommendation that a transparent electricity distribution system planning process that addresses the benefits of distributed generation, including cogeneration, should be created, the Governor responded:

> *I agree. An important benefit of clean distributed generation for electricity systems is that it can occur right at load centers, reducing the need for*

[5] Review of Major Integrated Energy Policy Report Recommendations (Review) at 1 (August 23, 2005 correspondence to Honorable Don Perata).

further infrastructure additions. The CPUC should develop tariffs that encourage the installation of distributed generation and cogeneration systems.[6]

The Governor concluded his review by stating in pertinent part: "*[t]he Energy Report is, as I have modified its assessments and recommendations pursuant to Public Resources Code 25307(a-b), a sound basis for energy policy analysis and development, going forward. I expect all state agencies to use it as a common foundation for making their energy related decisions*." (Review at 14)

Most significantly, the recommendations contained in the Report are critical in light of the positions taken by the California utilities at the CPUC regarding the preservation of existing, and development of new, CHP resources. In sharp contrast to the positive recommendations contained in the Report, Southern California Edison Company (SCE) and Pacific Gas & Electric Company (PG&E) (collectively, Utilities) proposals in the long-term QF policy proceeding (R.04-04-003) would actually serve to discourage these valuable resources.

Cogen-1

The Utilities offer both existing and new CHP facilities three options as an alternative to the targeted recommendations contained in the Report. The first is for CHP resources to bid into utility requests for offers (RFOs).[7] The Utilities submit this proposal despite the fact that for the most part, they seek resources which are freely dispatchable; a status which the Report recognizes CHP does not have due to CHP's thermal load requirements. (IEPR at 77) As one example of this, on November 3, 2005, Watson Cogeneration Company submitted

Cogen-2

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6 Review at 6.

7 PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 109.

comments to the Energy Commission on the IEPR describing in part their experience with a recent RFO issued by SCE. A copy of Watson's comments is attached for the Energy Commission's convenient reference. Moreover, the offer for CHP to bid into RFOs (even assuming that non-dispatchable CHP would be eligible to bid in the RFO) seems particularly hollow when the utilities continue to acquire significant resources, resources which displace the need for CHP capacity, completely outside of the RFO process.

The second option is for CHP resources to attempt to negotiate long-term contracts with the Utilities.[8] The IEPR Committee is well aware of and has appropriately noted in the IEPR that the IOUs recent history of negotiating long term contracts with CHP operators has not been a positive one. (IEPR at 76) Cogen-3

The third option is a one year contract at market prices.[9] One year contracts simply do not incent generators to invest in upgrades or significant maintenance to existing facilities or to build new facilities. As noted in the IEPR, long-term contracts with a minimum ten year term are required in order for CHP owners to make well-informed investment decisions and provide assurances to both the Energy Commission and the Utilities of the long-term availability of these resources. (IEPR at 77-78) Cogen-4

The primary concern of industrial processes that require steam is insuring that steam supply. This can be accomplished through either existing or new Cogen-5

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[8] PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 112.

[9] PG&E Prepared Testimony in R.04-04-003, August 31, 2005 at 4-1; SCE Prepared Opening Testimony in R.04-04-003, August 31, 2005 at 113.

CHP facilities or through boilers. The CHP option requires a repository for the electric energy produced by the CHP process, often on a 24/7 basis. Options which threaten the reliable delivery of steam to the industrial process simply will not encourage either existing or new CHP operations. The Utilities proposals do not provide any assurances that industrial facilities can rely upon CHP to provide their steam requirements because none of the Utilities proposals insures a reliable repository for the CHP process electric energy. In short, the Utilities proposals serve to discourage CHP and will not achieve the Energy Commission's IEPR goals of retaining existing CHP capacity and encouraging the development of new capacity. The Utilities' hostility to CHP operators is further exemplified by testimony filed by PG&E in R.04-04-003 which attempts to incorrectly characterize state policy preferences toward CHP (presumably including the Energy Commission's IEPR) as only applying to facilities smaller than 20 MW;[10] an interpretation clearly at odds with the express intent of the IEPR to preserve and promote CHP of all sizes.

CONCLUSION

The Utilities' proposals for CHP at the CPUC emphasize how critical the Report's recommendations are for the preservation of existing CHP resources and the encouragement of new resources. CAC/EPUC fully supports the Report's recommendations and look forward to working with the Energy Commission on implementation of the recommendations in the CPUC's 2006 procurement process.

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[10] PG&E Rebuttal Testimony in R.04-04-003 at 2-11.

Dated: November 8, 2005

Respectfully submitted,

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ATTACHMENT

Watson Cogeneration Company
22850 South Wilmington Avenue
Carson, California 90749-6203

Thomas A. Lu
Executive Director

November 3, 2005

Mr. Joe Desmond
Chairman
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Mr. Michael Peevey
President
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Implementing the 2005 IEPR - Creating a Cogeneration Portfolio Standard

Dear Chairman Desmond and President Peevey:

We support the California Energy Commission's efforts to establish sound energy policy for California and appreciate your recognition of the important role and benefits that cogeneration provides to our state. Implementation of your cogeneration policy recommendations, in the form of a Cogeneration Portfolio Standard, constitutes a key element of the necessary framework to maintain continued investment in cogeneration resources that are so important to California energy supply and security. Regulatory certainty in the form of long-term commitments for the delivery of power under just and reasonable conditions is vital to a cogeneration facility and its thermal host.

Cogeneration is among the most effective and efficient forms of power generation available because it generates very real and quantifiable environmental and energy savings compared to separate production of heat and electricity. The Energy Action Plan II and 2005 Integrated Energy Policy Report (IEPR or the Report) have correctly identified cogeneration as a key element of California's loading order strategy that will help meet the state's energy efficiency and renewable energy goals. Therefore, continued promotion of cogeneration in California in the form of a Cogeneration Portfolio Standard is part of a sound strategy for the efficient use of energy that is both complementary and supplementary to the strategy of increased use of renewables.

Businesses in California with legitimate thermal needs utilize heat associated with the production of electricity to make cogeneration a cost effective, low-emission generation option that provides for efficient use of limited natural gas resources and helps meet California's growing energy needs. Cogeneration is a viable end-use efficiency strategy for California businesses and an essential element of customer choice that helps keep industrial users commercially competitive while also providing the benefits of diversification that are critical to the continued reliability and security of California's power grid, transportation fuels and industrial infrastructures.

Cogeneration enhances reliability by decreasing the grid's peak load requirements and benefits the IOU's and ratepayers by relieving congestion on the transmission system, providing ancillary services and reducing electric line losses and transmission costs. From a security standpoint, cogeneration facilities were also largely responsible for keeping the lights on in California during the darkest days of the 2000-2001 energy crisis, many running months without certainty of payment in order to maintain the viability of critical state industrial infrastructure. Most recently, Hurricanes Rita and Katrina in the Gulf Coast area of the United States have provided additional lessons in the importance of cogeneration in sustaining infrastructure so critical to our economy and national security. On-site cogeneration at industrial facilities such as refineries and chemical plants were key to getting those operations up and running again while other facilities dependent upon the power grid waited weeks for restoration of transmission facilities.

Watson Cogeneration Company is an important contributor to California's energy infrastructure. The facility produces enough power to supply over 400,000 homes and, as the sole provider of process steam and power to BP's Carson refinery, is literally the engine behind the production of 20% of California's in-state production of gasoline, 30% of its diesel, and a significant portion of the jet fuel that supplies LAX. However, given the current state of the California energy market, Watson's ability to continue to fulfill this role depends on the certainty that only a long-term power sales agreement can provide; it is the certainty of a buyer for the project's power that ensures Watson will be able to cogenerate both steam and electricity dependably, efficiently, and without interruption.

Simply put, unless Watson has the certainty of a home for its base-loaded power after its current SCE contract expires in April 2008, it cannot commit to continue to provide process steam to the BP refinery. In turn, BP's need for a reliable supply of steam is too critical to allow it to wait until the last minute in the hopes that a buyer for Watson's power will suddenly emerge. Absent firm commitments on steam and power sales, at some point the refinery will have no choice but to secure an alternative source of reliable steam (including industrial boilers); this will both eliminate the inherent environmental and fuel efficiencies provided by Watson as a cogeneration facility, and jeopardize Watson's ability to continue to generate power for the LA basin.

Testimony provided to the CEC and its staff during the IEPR proceedings has clearly identified and accurately described the obstacles faced by other existing and proposed cogeneration projects. The utilities in their filings and comments to the Report have intimated that there are no major barriers to the development of cogeneration in California. However, clear and compelling evidence presented during hearings for the IEPR and elsewhere demonstrates that this is simply not the case.

SCE issued a 5-Year Request for Offers on or about July 1, 2005 in which it invited non-dispatchable qualifying facilities to submit offers. Watson's view is that SCE's expressed encouragement for **non-dispatchable** base-loaded QFs to participate in this RFO appeared to be in direct conflict with their stated preference for this RFO. The RFO Transmittal letter clearly stated that, "SCE is primarily interested in receiving offers for **dispatchable** *(emphasis added)*, low capacity cost, higher heat rate tolled units located within the Los Angeles area …" and "QF resources that are **dispatchable** *(emphasis added)* during on-peak periods or curtailable during mid-peak and/or off-peak periods...". QFs, by their basic design and purpose, are inherently **non-dispatchable**, which brings into question the genuineness of the invitation for QFs to participate in this RFO. Nevertheless, Watson submitted a timely and competitive offer in response to this RFO. Now, a full 4 months after the solicitation, Watson still faces cessation of its contract, despite its long history of dependable service to SCE. Perhaps this is why standard offer contracts for non-dispatchable cogeneration resources were necessary in the first place, to ensure that sound energy policy could be fairly implemented for the benefit of Californians.

The CEC has proposed realistic and sound solutions to the obstacles facing cogeneration as identified in the IEPR and correctly states, “current state policy must change for California to tap into this potential generation source and, equally important, retain the existing pool of CHP (cogeneration) so critical to the reliable operation of the grid.” Regulatory certainty is vital to a cogeneration facility and its thermal host; therefore the state policy objectives identified in the IEPR should be implemented by the creation of a Cogeneration Portfolio Standard.

By instituting a ***Cogeneration Portfolio Standard***, the CEC and CPUC can establish the necessary framework to maintain continued investment in cogeneration resources that are so important to California energy supply and security. Elements of an effective plan should include

(1) A minimum goal for procurement from cogeneration resources in the IOUs integrated resource investment plans,

(2) A requirement that, absent the availability of a viable long-term standard offer contract, each of the state IOUs enter into negotiations for bilateral extensions of existing cogeneration QF contracts within a reasonable timeframe,

(3) Meaningful recognition (i.e. through dispatch restrictions and CAISO tariffs) that cogeneration resources run in order to meet the needs of thermal hosts. For operational reasons, most cogeneration facilities must run continuously on an around-the-clock basis.

(4) Incentives for cogeneration projects that reduce congestion by providing transmission and distribution benefits in load centers (e.g. through a local reliability capacity payment)

Watson Cogeneration Company urges the CEC, CPUC, and CAISO to work together and take the necessary actions to implement a sound cogeneration policy that ensures efficient cogeneration resources can continue to meet California’s growing energy needs by removing the regulatory barriers and uncertainty that are discouraging cogeneration retention and new development.

Respectfully,
Watson Cogeneration Company

Thomas A. Lu
Executive Director

cc: Mike Chrisman, Secretary for Resources, State of California
Dan Skopec, Deputy Cabinet Secretary, Office of the Governor
Dennis Albiani, Deputy Legislative Secretary, Office of the Governor
Geoffrey Brown, Commissioner, California Public Utility Commission
Susan Kennedy, Commissioner, California Public Utility Commission
Dian Grueneich, Commissioner, California Public Utility Commission

John Bohn, Commissioner, California Public Utility Commission
Jackalyne Pfannenstiel, Vice-Chair, California Energy Commission
Arthur Rosenfeld, Commissioner, California Energy Commission
James Boyd, Commissioner, California Energy Commission
John Geesman, Commissioner, California Energy Commission

BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF
CONSTELLATION ENERGY COMMODITIES GROUP, INC. AND CONSTELLATION NEWNERGY, INC. ON
CALIFORNIA ENERGY COMMISSION DRAFT TRANSMITTAL REPORT

November 8, 2005

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BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the *2005 Integrated Energy Policy Report*	Docket No. 04-IEP-1K

COMMENTS OF CONSTELLATION ENERGY COMMODITIES GROUP, INC. AND CONSTELLATION NEWNERGY, INC.ON CALIFORNIA ENERGY COMMISSION DRAFT TRANSMITTAL REPORT

I. Introduction and Summary

On October 25, 2005, the California Energy Commission ("CEC") issued the *Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations* ("Transmittal Report") to the California Public Utilities Commission ("CPUC"). Pursuant to *Notice of Committee Hearing and Availability of the 2005 Committee Draft Transmittal Report*, the CEC invited comments on the Transmittal Report and Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (collectively "Constellation") appreciates this opportunity to do so.

In general, Constellation finds the Transmittal Report to provide a wealth of information and documentation that will serve the CPUC's upcoming 2006 Long Term Procurement Process ("2006 LTPP") well. In addition to providing the specific information on the range of need that each of the IOUs must address in the 2006 LTPP, the CEC's expressed commitment to ensuring that the 2006 LTPP is an open and transparent process is a very welcome and necessary element of California's continued progress to workable competitive markets. However, there is one area of concern with the Transmittal Report that Constellation will address in these comments. The concern has to do with the CEC's specific advocacy for the IOUs to enter into new long term contracts despite the fact that other approaches and mechanisms to support infrastructure development are currently under consideration at the CPUC and CAISO.[1] While it is important to ensure that the deployment of new generation resources follows the loading order and encourages new, environmentally beneficial conventional generation, Constellation believes the particular advocacy in the Transmittal Report is premature. Constellation's specific concerns and recommendations in regard to these issues are as follows:

A. Execution by the IOUs of long term power purchase contracts that substitute for rate based generation (or IOU self-build, should that be considered) will perpetuate and prolong the existing hybrid market structure[2] in California, and undermine the effectiveness of competitive market structures, the development of which are already well underway in several CPUC and CAISO proceedings.[3] Constellation -1

B. To the extent that such long term IOU contracts are deemed necessary to address urgent reliability requirements that cannot be met within the competitive wholesale market framework being implemented by the CPUC and CAISO, their scope and duration must be carefully circumscribed to ensure that they do not compromise on the development of the nascent competitive wholesale markets.

C. To ensure that there will not be continued reliance on such contracts to ensure reliability – i.e., in order to ensure that competitive market structures will be successful, steps must be taken to reform IOU procurement practices that lead to such contracts. Specifically, IOU procurement practices should be designed to move increasingly toward full requirements competitive procurement practices in Constellation -2

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[1] See *Transmittal Report* at page 9: "A careful review of the record developed during this proceeding demonstrates that policies encouraging long-term contracts would increase deployment of both new renewable and new conventional generations. Provide a hedge against increasing natural gas prices, and increase environmental and reliability benefits associated with diminished reliance on the state's aging fleet of existing plants." See also page 11: "In sum, the most important action the CPUC can take in the 2006 procurement proceeding is to compel the IOUs to enter into long-term contracts, particularly contracts with renewable facilities. Long-term contracts will encourage development of new conventional and renewable resources, both reducing reliance on aging, less efficient plants and providing important gas-price hedging advantages. The result will be a more reliable market, with environmental and economic benefits accruing to all utility customers."

[2] As used herein, the "hybrid market structure" refers to the continued existence of vertically integrated IOU structures in which a significant percentage of available generating capacity is still owned and operated pursuant to cost-of-service/rate-based regulation. In addition, an additional significant amount of generating capacity is committed to IOU operation via long term Power Purchase Agreement ("PPAs"), the cost recovery of which is assured via rate-based regulation.

[3] *I.e.*, CPUC Docket R.04-04-003 and upcoming LTPP proceeding per D.05-10-031; FERC Docket EL05-146 re MOO reform and RCST capacity backstop contract; and CAISO MRTU effort, with upcoming tariff filing.

which the IOUs procure from the wholesale market the products and services they need to meet their load obligations.

D. Constellation respectfully suggests that the Transmittal Report simply highlight the need to have mechanisms in place to support infrastructure development, without particularly advocating for any single structure or form, particularly since the CPUC and CAISO are in the process of undertaking additional proceedings to complete the Resource Adequacy Requirement mechanism and develop a formalized capacity market structure for California. Constellation -3

E. Constellation respectfully suggests that the Transmittal Report be revised to recognize the impact on retail market competition that will occur due to a failure to anticipate departing loads and the resulting potential over-procurement of resources by utilities. Constellation -4

Constellation raises these concerns only to highlight its views on the impact of IOU procurement practices on the development of competitive wholesale markets (and, in turn, the development of competitive retail markets). The CEC has carefully developed the needs assessment contained in the Transmittal Report, which is a critical element to the upcoming CPUC proceedings. In the upcoming CPUC 2006 LTPP case, Constellation plans to re-introduce the concept of "full requirements competitive procurement" that it first presented in testimony in the last CPUC LTPP procurement docket.[4]

II. Constellation Comments

A. Allowing New Resource Requirements To Be Met Through New Long Term IOU Contracts Of The Traditional PPA Type (Or IOU Self-Build) Will Delay, If Not Preclude, The Development Of Competitive Wholesale Markets.

The stability of wholesale market structures and confidence that regulatory policy changes will not undermine the value of investments is key to ensuring new investments in developing competitive generation assets in California. Such stability will not be achieved, nor will investor confidence develop, if new infrastructure is procured through mechanisms that Constellation -5

[4] *See*, August 6, 2004 Direct Testimony of Constellation Power Source in CPUC Docket R.04-04-003; *See also*, CPUC D.04-12-048, pages 175-176, wherein the CPUC stated that the slice of load concept was to be considered as one of the "second generation" topics.

perpetuate California's currently existing hybrid market structure. Under the existing hybrid market structure, assets (both physical and contractual) that have rate-based cost recovery protection do not compete on a level playing field with assets that do not have guaranteed rate recovery protection. In short, the current hybrid market structure skews market price signals upon which the merchant assets rely for revenues and upon which they rely to incent buyers to execute long term contracts. It is simply not possible to build investor confidence when resource requirements are only successfully developed outside the competitive market structures. Accordingly, Constellation does not believe that the Transmittal Report should advocate new long-term contracts that substitute for rate based generation as a permanent market feature to promote new asset development.

B. Urgently Needed Near Term Resources, Once Identified, Must Be Procured With Special Attention Given To How Those Investments Can Be Managed So As Not To Undermine The Long Term Development Of Competitive Wholesale Markets.

There is no arguing, however, that investor confidence in wholesale market structures will take some time to develop. In contrast, there is concern that California needs new generating capacity in the immediate term. Moreover, today's conventional wisdom holds that a long term contract between a developer and an IOU is the only way to secure financing for new generation resources. Conflicts between these two goals - securing immediate investment, while not undermining confidence in the developing competitive wholesale markets – can and must be managed.

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In order to manage these somewhat conflicting goals, the parameters of the specific resources that are urgently needed must be clearly and narrowly defined as to the magnitude and locational requirements, and the contracts that the IOUs enter into must be for as short a duration as possible. Consideration should also be given as to whether any increase in the IOU share of asset ownership (both physical or contractual) necessary to secure the new generation asset development in the near term should be offset by IOU divestiture of a similar amount of IOU owned generation through a competitive offering, so that there is no net change in the current market balance between existing IOU controlled assets (physical and contractual assets) and non-utility assets.

Constellation believes that these issues will be best addressed in the upcoming CPUC LTPP proceeding. Accordingly, the Transmittal Report should acknowledge that the CPUC will be reviewing various "second generation" issues with the intent of creating long-term market structures that will support and encourage development of new generation infrastructure through workable wholesale competition.

C. Shifting IOU Procurement Practices Away From Procurement Of Power Supply Infrastructure To Procurement Of Energy Products And Services Would Eliminate Many Of The Issues That Currently Impede Competitive Investment, Would Shield Ratepayers From Market Risk, And Would Facilitate The Development Of Competitive Retail Markets.

The focus of the LTPP has been to analyze infrastructure requirements necessary for the IOUs to serve their load. Constellation believes that the efforts underway at the CPUC and CAISO will ensure that price signals in the wholesale energy, capacity, and ancillary services markets will lead to infrastructure investment when and where it is needed. Entities that serve load at the retail level should seek the products and services they need to meet their load obligations from the wholesale markets. This is already the case for Electricity Service Providers ("ESPs") and Community Choice Aggregators ("CCAs"). But it is not the case for the IOUs in the hybrid market. Current procurement regulations imposed on the IOUs require them to submit plans to secure assets (both physical and contractual) to serve anticipated load. In

Constellation-7

meeting those requirements, the IOUs effectively transfer market risks associated with those procurement decisions and investments onto their ratepayers.

Constellation has suggested before the CPUC that the IOUs should offer to wholesale suppliers the opportunity to provide products and services to meet their load obligations, as those load obligations change due to weather, customer switching, load growth, and other factors that influence hour to hour and year to year demand for electricity - rather than being subject to procurement practice regulations that require them to secure specific power supply resources that do not match their load serving obligations. Such procurement practices would move the risks associated with the IOU's current procurement approach away from the IOUs (and their ratepayers) and back to the wholesale suppliers, entities that are in the best position to manage those risks. Such full requirements competitive procurement practices are widespread throughout the Northeast and Mid-Atlantic, and can serve as useful models here in California.

Not only would the full requirement competitive procurement processes serve to shift market risk away from ratepayers, as noted above, it would also help to resolve several of the issues raised in the Transmittal Report. For instance, full requirements competitive procurement practices by the utilities would shift customer attrition risk away from the utilities and thus eliminate one of the key reasons that the IOUs have been reluctant to support customer choice. Furthermore, where these competitive procurement processes have been implemented, the bid evaluation processes are based on one parameter only – price, eliminating many, if not all, the evaluation transparency issues raised in the Transmittal Report. Finally, implementation of these procurement practices by the IOUs would provide a strong measure of support for the development of wholesale markets, rather than conflicting with their development, by assuring wholesale suppliers that there will be opportunities to serve load at a wholesale level through continuous and transparent solicitations.

D. Departing Load Assumptions and the Resultant Resource Procurements Will Negatively Impact Retail Market Development

Constellation does not believe it is appropriate for the Transmittal Report to advance concepts which would undermine retail customer choice. Thus, Constellation takes issue with the Transmittal Report to the extent that it concludes that resource plans should be based upon load forecasts that do not include any departing load, especially given that the study spans through 2016.[5] Even if the DA market suspension is not lifted until the last DWR contract expires in the 2012-2013 timeframe, *some* level of new DA load during 2012-2013 should be assumed. For the CEC to assume no new departing load in the Transmittal Report will likely lead to the IOUs over procuring long-term resources over that timeframe.

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Moreover, it is overly simplistic to say that the result of over-procurement is merely economic[6] as the costs associated with the over-procurement will continue to be layered upon future departing customers, presumably as nonbypassable charges, and will have a negative impact on the DA market. To that end, care needs to be taken about how policies for encouraging long-term contracting, or term contracting for urgently needed resources, will affect the retail market. Ultimately, retail markets were envisioned to operate independently of utility cost for bundled customer procurement. However, DWR Contracts have, and will continue to have, an affect on customer choices between retail and utility bundled services. Other contracts may do the same. Thus, it is short-sighted to increase the reliance on utility term contracting without also acknowledging and mitigating the very real cost and retail market structure issues that arise as a result of those policies. Failure to explicitly acknowledge cost treatment now

[5] *See* Transmittal Report, § 5.2 page 43 in published version (page 40 in on-line version).
[6] *See* Transmittal Report, page 42, citing Hal LaFlash (page 39 in the on-line version).

effectively means that the departing customers will likely carry the burden of a cost obligation for those utility decisions well into the future, undermining any benefits they would otherwise receive from those market structures. Failure to take steps to avoid a new generation of stranded costs will essentially re-create the pre-AB 1890 environment.

It is also disingenuous to say that utility planning uncertainty is resolved solely through the structure of the coming and going rules at the Commission.[7] The CPUC has already provided rules for customer re-entry, six months prior notification, with a three-year stay requirement. Those rules allow utilities to adjust their procurement plans accordingly. To direct otherwise would result in a presumption that the only good utility portfolio is a long-term utility portfolio. By all reasoning and from past experience, relying too strongly either on spot markets or long-term contracts creates a risky profile. If we continue to have utility contracting on behalf of customers and do not adopt the "outsourcing" proposal that Constellation advocates, then utilities should maintain a balanced portfolio of resources which will include some short-term, including spot purchases, some medium term and some long-term contracts. Therefore, with such notice, a utility should, at a minimum, be expected to accommodate both customer migrations and customer returns through a balanced portfolio approach and should be held accountable for such decisions. Constellation does not believe that there is any need to modify the coming and going rules to make them more restrictive for direct access customers.

Rather, customer migration and other attrition risks can best be accommodated through the outsourcing functions espoused by Constellation as in that instance, load forecasting functions are the responsibility of the supplier and the retail market is free to develop absent the additional costs associated with unwise procurement practices.

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[7] *See* Transmittal Report, page 43 in published version (page 40 in on-line version).

III. Conclusion

For the reasons described in detail above, Constellation respectfully asks the CEC to revise the Transmittal Report with respect to its advocacy for long-term IOU contracting.

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Respectfully submitted,

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